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Energy Procedia 37 (2013) 6617 – 6624

Energy Procedia

GHGT-11

Simulation of CO_2-EGS in a fractured reservoir with salt precipitation

Andrea Borgia*, Karsten Pruess, Timothy J. Kneafsey, Curtis M. Oldenburg, and Lehua Pan

Earth Sciences Division, Lawrence Berkeley National Laboratory, 1 Cyclotron Rd., Berkeley, CA 94720, USA.

Abstract

The use of CO_2 as a working fluid in place of formation brines in Enhanced Geothermal Systems (EGS) could allow, in addition to CO_2 sequestration, a more efficient recovery of reservoir heat for any given pressure gradient between injection and production wells. We simulate an idealized low-salinity brine-filled reservoir in which we inject CO_2. We produce heat from the extracted fluid that is at first just brine, later brine + CO_2, and finally CO_2 only. As the CO_2 plume develops the aquifer dries out, precipitating salt and inducing clogging of the fractures in proximity to the production well. To mitigate this effect, we have simulated combined brine and CO_2 injection that, at specific mass fractions, doubles the life of the well but limits the rate of heat extraction. The total heat extracted over the life of the well is 40% larger than in the dry CO_2 case. Simulation of more realistic geologic settings with involvement of chemical reactions would be necessary to evaluate the feasibility of CO_2-EGS in any particular geothermal system.

Keywords: CO_2-EGS; Geothermal energy; Reservoir modeling; Salt precipitation.

1. Introduction

The production of heat-energy from Enhanced Geothermal Systems (EGS) generally uses water as the working fluid to bring energy to the surface. This standard methodology has some disadvantages when applied to enhanced geothermal systems (EGS), principally related to strong water-rock chemical reactions, but also in terms of environmental impacts through potential overdraft of shallow aquifers containing valuable water resources.

The concept of using CO_2 in place of water as a heat-transfer fluid results in clear advantages [1, 2] because of (1) a larger rate of heat extraction for the same production pressure gradient, (2) less fluid-rock

* Corresponding author. Tel.: +1-5104952304.
E-mail address: aborgia@lbl.gov.

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Selection and/or peer-review under responsibility of GHGT
doi:10.1016/j.egypro.2013.06.594

reactivity, and (3) less demand for scarce ground- or surface-water resources. Here we point out also the potential of (4) a large utilization and sequestration opportunity for CO_2.

2. Simulation with ECO2H

To simulate an EGS developed with CO_2, we use the new TOUGH2 module ECO2H [3], which models the H_2O-CO_2-NaCl system at high temperature (up to 243 °C) and high pressure (67.6 MPa). Our idealized EGS consists of a five-well geometry in a reservoir of 1 km thickness and 1 km spacing along the diagonal between opposite corner wells [4] (Fig. 1). Taking advantage of the symmetry of the system, we model only 1/8 of the actual rock volume, but give results for the full rock volume. The grid has 20 × 10-horizontal and 20-vertical grid blocks. Our model includes the simulation of fracture/matrix fluid flow and salt precipitation via the multiple interacting continua (MINC) dual-porosity conceptualization. Accordingly, "connected" to the fractures are four concentric matrix shells per each grid block [5]. Fracture spacing is 10 m and fracture aperture is 10^{-3} m.

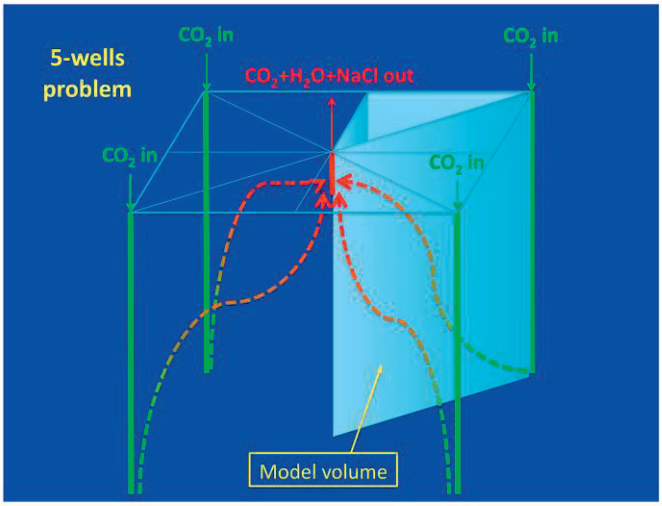

Fig. 1. Five-well problem. CO_2 with a variable amount of brine is injected at the corner wells and production of hot fluid occurs at the central well.

The model also accounts for two-phase flow and permeability reduction due to salt precipitation based on the model of Verma and Pruess [6]. The model has a normal geothermal gradient of 40 °C/km, starting with 160 °C at 3500 m depth and reaching 200 °C at 4500 m depth. Pressure is hydrostatic from 3500 m downward, calculated for the specific salinity of the EGS reservoir brine. The top and bottom boundaries are closed (no-flow and insulated).

CO_2 is injected at the four corner-wells into the lower 200 m of the reservoir at constant overpressure of 2 MPa above original reservoir pressure with a temperature of 20°C. The central well produces fluid at a constant pressure of 2 MPa below original reservoir pressure. Salinity was varied in the study between a salt mass fraction (Xsm) of 0.01 and 0.15 (Fig. 2); here we present the results of the 0.01 mass fraction case only.

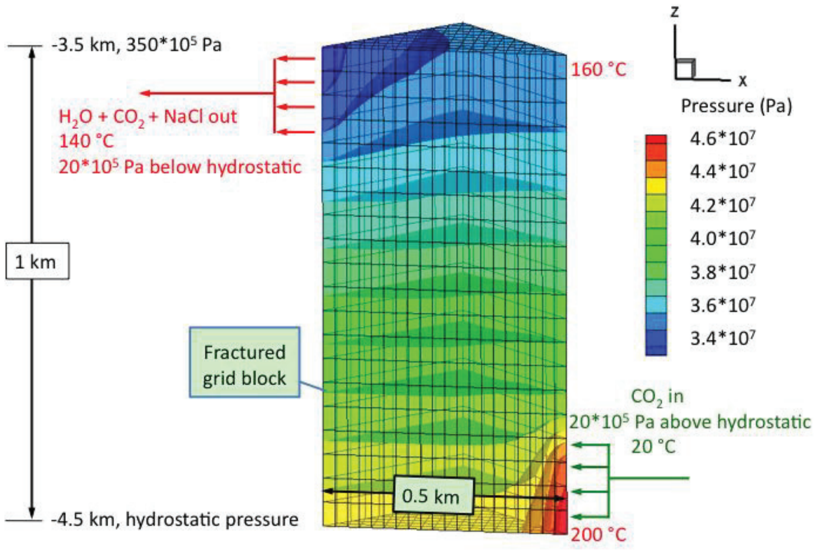

Fig. 2. Initial and boundary conditions. Injection occurs at the bottom right of the figure, and production from the upper left. See text for further explanation.

3. Results

3.1. Injection of dry CO_2

In the simulations, brine is the extracted fluid when production begins. After a few weeks, a mixture of brine + CO_2 is produced, then CO_2 + water vapor, and finally dry CO_2 only. Once the injected CO_2 reaches the production well, a drastic drop in heat and fluid production occurs, resulting from a reduction in effective permeability due to two-phase flow (liquid + gas) in the proximity of the production well [7, 8]. As the aqueous phase disappears (i.e., the aquifer dries out), the CO_2 flow rate increases over about 1-3 years reaching a maximum rate that is about 60% larger than the initial rate (Fig. 3). After this maximum rate of production, at around 5 years after CO_2 injection started, there is a second drastic drop in production because of halite precipitation and clogging of the reservoir close to the production well.

This phenomena is apparently similar to what has been described by Kleynitz et al. [9], Lorentz and Muller [10], Xu et al. [11], Giorgis et al. [12], and Tambach et al. [13] for production and reinjection in gas reservoirs, and injection into geothermal wells. It results from the migration of a highly saline brine front from the injection to the production wells associated with water evaporation into the CO_2 stream. This process induces halite precipitation in the proximity of the production well. Salt precipitation eventually “clogs up” the system at a solid saturation equal to 20% of pore volume based on the Verma and Pruess model [6].

The process of increasing salt concentration in the brine is shown in Fig. 4 (a, b, and c). The high-salinity envelope propagates in front of the dry-CO_2 plume until it reaches the production well in less than five years. Continuing brine migration from the matrix to the fractures and H_2O evaporation into the CO_2 eventually leads to salt precipitation and fracture clogging near the production well (Fig. 5a, b, and c).

3.2. Injection of CO_2 + brine

To attempt to reduce the effect of reservoir clogging due to salt precipitation, we have tested the possibility of reinjecting the extracted brine along with the CO_2 in a two-phase mixture with 45% CO_2 and 55% brine by volume. This mixture was selected based on a set of experiments which showed that larger CO_2 fractions induce salt precipitation with rapid system clogging, and smaller CO_2 fractions maintain two phase flow in the system inhibiting enhanced recovery of heat.

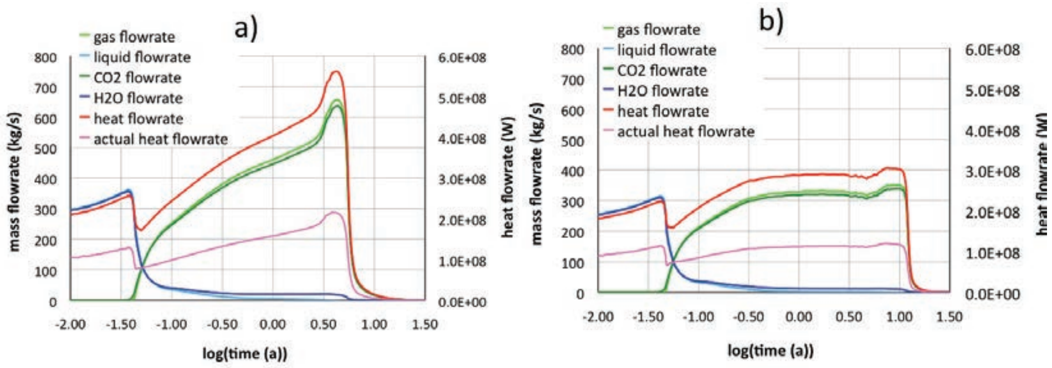

Fig. 3. Mass and heat flow rates at the production well. a) dry CO_2 injection simulation; b) brine + CO_2 injection simulation. Actual heat flow rate is the heat produced minus that injected. See text for explanation.

The time evolution of the flow rate at the production well (Fig. 3b) shows the same general pattern found for the dry-CO_2 case (Fig. 3a). There are, however, two major differences:

1) the time at which clogging occurs increases from about 5 to more than 11 years;
2) the maximum heat flow rate decreases by about 45% relative to the maximum heat flow rate of the dry-CO_2 case.

The combination of these two differences results in a total actual heat extracted during the life of the well that is about 40% larger for the brine+CO_2 case than for the dry-CO_2 case.

This result can be understood by comparing salt concentration in the brine for both cases, dry-CO_2 (Fig. 4a, b, and c) versus brine + CO_2 injections (Fig. 4d, e, and f). While in the first case only one high-salinity envelope is generated in front of the CO_2–saturated volume, in the second case two high-salinity envelopes are formed, one in front and one behind the CO_2-rich volume. Like the dry-CO_2 case, the front at the leading edge develops as the water is driven out of the fractures by the propagating CO_2 plume. The trailing front is an evaporation front. In fact, the injected CO_2 increases in temperature as it flows upward through the rock fractures, evolving from saturated to unsaturated in H_2O. Therefore, water evaporates from the brine into the CO_2 plume, concentrating salt in the brine left behind.

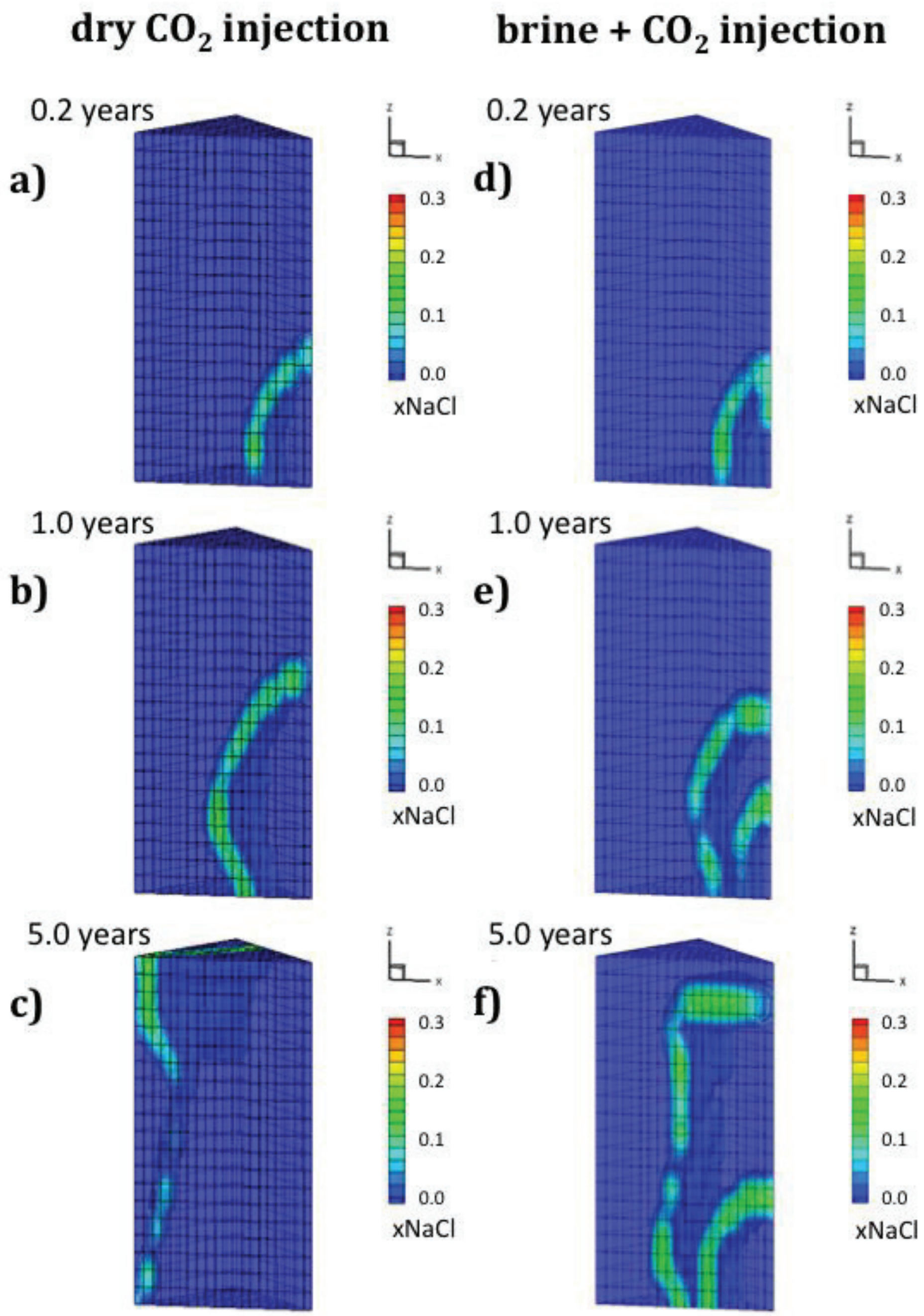

Fig. 4. Salt mass fraction (XNACL) in the brine contained in the reservoir's fractures at 0.2 years (a and d), 1 year (b and e), and 5 years (c and f) for the case of dry CO_2 (left) or brine+CO_2 (right) injections for the model configuration depicted in Fig. 2. See text for explanation.

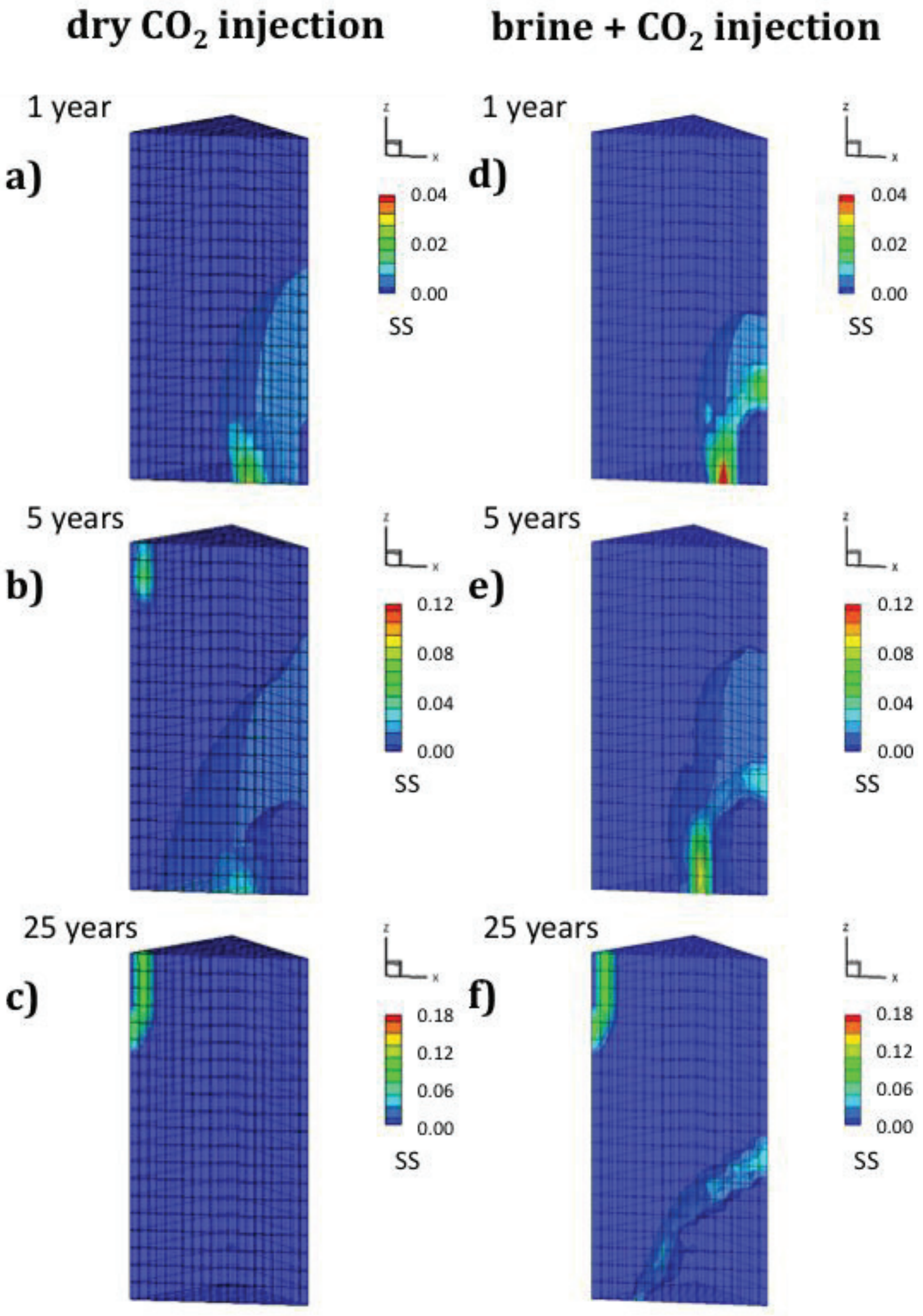

Fig. 5. Halite volume fraction (SS) in fractures at 1 year (a and d), 5 years (b and e) and 25 years (c and f) for the case of dry CO_2 (left) or brine+CO_2 (right) injection. Scale changes over time. See text for explanation.

Comparing volume fraction of halite in the fractures for the dry-CO_2 case (Fig. 5a, b, and c) with the brine + CO_2 injection case (Fig. 5d, e, and f), one can see how clogging develops in the reservoir. In the second of these two cases, halite precipitation at the production well is delayed for a time period that is much longer than that of the first case. During this period precipitation remains confined to the evaporation front behind the CO_2-plume.

4. Conclusions

In addition to the potential to store CO_2 in the reservoir, the most important benefit of using CO_2 as working fluid for EGS is that the actual heat flow rate from a given reservoir could be up to five times larger than the heat flow rate achievable using the formation brine as the working fluid [7, 14]. The maximum benefit is achieved after the system has gone through the process of substituting the formation brine with CO_2 [7, 9].

Re-injecting the extracted brine with the CO_2 delays the clogging of the fractures from about 5 to over 11 years, but reduces the heat flow rate significantly. The balance of these two effects, though, is still positive giving a total heat produced that is about 40% larger than that produced by injecting dry CO_2 only. Testing of different schemes of water injection may allow resolving the problems associated with salt precipitation while developing CO_2-EGS in fractured saline geothermal aquifers. Testing more realistic geologic reservoirs with more complex flow patterns than the ones investigated here, and with other fracture plugging models will be necessary to evaluate the feasibility of CO_2-EGS in any particular geothermal reservoir. Similarly, for evaluating CO_2 trapping for sequestration purposes, specific reservoir heterogeneity and caprock properties should be represented in the model.

Acknowledgements

This work was supported by the American Recovery and Reinvestment Act (ARRA), through the Assistant Secretary for Energy Efficiency and Renewable Energy (EERE), Office of Technology Development, Geothermal Technologies Program, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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